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Analysis Report

An Analysis of President Carter's Program to Reduce Utility Oil Consumption 50 Percent by 1990

December 1979

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An Analysis of President Carter's Program to Reduce Utility Oil Consumption 50 Percent by 1990

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ABSTRACT

This analysis report projects electric utility oil consumption in 1990 with and without the implementation of President Carter's proposed program to reduce current oil consumption 50 percent by 1990. Several case studies are analyzed to determine the impact of the program on electricity prices and the capital expenditures required to accomplish the reduced oil consumption goal.

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PREFACE

This Analysis Report was prepared in response to a request from the Utility and Coal Supply Policy Division of the Office of Policy and Evaluation, Department of Energy.

The report presents the results of an analysis of President Carter's program to reduce utility oil consumption 50 percent by 1990. The analysis was performed with the Midterm Energy Forecasting System to estimate the utility oil consumption with and without the President's program. Projections of oil consumption, electricity prices, and the capital required to construct new powerplants are discussed. The authors of this report are Betsy O'Brien and Gerald Price of the Coal and Electric Power Analysis Division.

This report was prepared under the general direction of David T. Hulett, Director of the Office of Energy Source Analysis, and Robert T. Eynon, Director of the Coal and Electric Power Analysis Division. The authors wish to acknowledge Lucinda Gilliam of the Coal and Electric Power Analysis Division, who contributed to the calculation of capital requirements contained in this report; Reginald Sanders and Irv Chamberlain of the Midterm Analysis Division,

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EXECUTIVE SUMMARY

In August 1979, President Carter announced a program to reduce utility oil consumption in steam powerplants 50 percent by 1990. The proposed legislation, to achieve this reduction, establishes an oil consumption ceiling for each utility in 1990 and assigns a fee of $12 per barrel in 1979 dollars on oil used in excess of these limits. Financial assistance is also proposed to provide funds for converting or replacing oil-fired powerplants.

For 1990, this report presents projections from several case studies to indicate the potential impact of the oil reduction program. The first two cases project a range on utility oil consumption in 1990, without limiting oil use, based on two extreme assumptions about the decision criteria for building new powerplants. In Case I, the powerplant capacity additions are limited to those which would be required to meet the projected increase in demand. In Case II, in contrast to Case I, decisions on capacity additions and operation of powerplants are assumed to be made based on minimizing the marginal cost of producing

electricity. Case III represents President Carter's program. The sensitivity of the results to a load management program is also presented.

Table 1 summarizes the 1990 projected oil and gas consumption, coal capacity expansion, and capital expenditures for the three cases described above. The Case I scenario assumes that the existing oil- and gas-fired powerplants would be operated to meet demand and, therefore, projects the high range on utility oil and gas consumption 1.59 million barrels per day and 2,594 billion cubic feet per year, respectively. Coal capacity expansion of 134 gigawatts (thousand megawatts) is projected to meet the increased demand, which is projected to have an average growth rate of 4.2 percent per year from 1977 to 1990.

The Case II results indicate lower oil consumption because new, coal-fired powerplants are projected to be constructed to replace existing, oil-fired powerplants, before their useful lifetime is over, due to a lower marginal cost in base mode, i.e., almost continuous operation. The replaced oil-fired powerplants would be retired early, used as reserve capacity, or operated at a lower annual utilization

Table 1 Electric Utility Oil and Gas Consumption, Coal Capacity Additions and Capital Expenditures: History and Alternate Projections for 1990

	1978	Build to Reserve Margin Case I	Minimize Life Cycle Costs Case II	President's Program Case III
Oil Consumption (thousand barrels per day)	1,742	1,594	934	850
Gas Consumption (billion cubic feet per year)	3,188	2,594	1,376	1,384
Coal Capacity (gigawatts)	211[a]	345	389	393
Coal Capacity Additions from 1979-1990 (gigawatts)		134	178	182
Capital Expenditures 1979-1990 (billion 1978 dollars)		199	237	242

[a] Existing as of January 1, 1978 and includes 7.46 GWe for oil-fired powerplants ordered to convert to coal under ESECA.

rate reducing the oil consumed. The gas consumption is less because of assumptions about the implementation of the Powerplant and Industrial Fuel Use Act which limits utility natural gas consumption in 1990. (See Appendix B for more details.) Additions of nuclear powerplant capacity are limited in each case to reflect current utility plans and the long lead time to license and construct new nuclear reactors. Therefore, only the coal-fired powerplants are projected to increase by 44 gigawatts in Case II over Case I, replacing the oil- and gas-fired units. The total capital expenditures from 1979 through 1990 increased from $199 billion 1978 dollars in Case I to $237 billion 1978 dollars in Case II.

Case III, which represents President Carter's program, places a national limit of 850 thousand barrels a day on utility oil consumption. This limit represents 50 percent of the oil currently used in steam plants and 100 percent of the oil used by plants meeting peak demand. Four additional gigawatts of coal capacity are projected to be built over those built in Case II, in order to reduce the oil consumption to the required limit. Additional nuclear

capacity beyond the limit would not be available because of the long lead time necessary for the construction of nuclear powerplants and the uncertainty of future licensing policy. Additional capital expenditures of 5-43 billion dollars over Cases II and I, respectively, would be required to reduce the oil consumption to the required limit.

The results from Case III indicate that the President's program is economically justifiable for they are similar to results from Case II, which minimize the cost of producing electricity over the long term. If utilities were not constrained by the availability of capital for constructing new powerplants, utility planners would be expected to make decisions similar to the results in Case II. The federal grants and loan guarantees in the proposed legislation would make a portion of the additional capital requirements available. In the short term, the electricity prices for consumers would increase slightly because of the additional, coal-fired capacity constructed to retire oil-fired powerplants that are still being paid for. The proposed legislation for federal grants and loan guarantees would reduce or possibly eliminate this

short term price increase from the oil reduction program. Finally, the program would have a significant effect on oil consumption if Case I closely reflects utility actions without the President's program.

1. INTRODUCTION

Currently the electric utility industry consumes 1.5 million barrels of oil per day in oil-fired steam plants. By 1990, the President's program would require a 50 percent reduction in the level of oil consumption currently used in existing facilities as well as those facilities under construction.

This report briefly discusses the proposed legislation to accomplish the required reduction; presents the results of three case studies from the Midterm Energy Forecasting System; and examines the sensitivity of the results to alternative, load management assumptions. The three case studies were designed to determine: whether the oil reduction program is economically justifiable; what effect the program has on electricity prices; and what capital expenditures will be required to construct new powerplants.

2. SPECIFICATIONS OF THE PRESIDENT'S PROGRAM

The proposed legislation, drafted by the Office of Policy and Evaluation of the Department of Energy, establishes oil consumption ceilings for the electric utility industry· assesses a fee of $12 per barrel in 1979 dollars for excessive oil use by a utility· requires a yearly report on a utility's compliance plan; and provides financial assistance (grants and loan guarantees) for powerplant modifications and construction. This legislation is designed to encourage the utilities to shift from oil to coal during the 1980's and to reduce oil consumption by 1990.

The consumption ceilings are implemented by issuing tickets (representing an allowance) to utilities that burned more than 50,000 barrels of oil per year in steam-based operations from 1974 through 1978. Utilities that consumed more than 250,000 barrels per year would be required to reduce the average 1974-1978 consumption in boilers, plus projected consumption by plants under construction, by 50 percent in 1990. Utilities that used from 50,000 to 250,000 barrels per year in 1974-1978 would be allowed to use the same level in

1990 and utilities that burned less than 50,000 barrels per year would be exempt but must purchase tickets from other utilities to consume more than 50,000 barrels per year. Utilities would be allowed to burn as much oil in nonsteam operations, i.e., turbines, in 1990 as consumed in the base period.

To enforce the 1990 targets, a fee of $12 per barrel in 1979 dollars would be charged for each barrel of oil a utility used above the level allowed through oil consumption tickets issued directly to the utility from the Government or purchased from other utilities. It is estimated that this fee would increase the cost of electricity generated with an oil-fired steam plant by 2 cents per kilowatt hour (1979 dollars). A compliance plan must be submitted to the Department of Energy yearly by utilities that used more than 250,000 barrels per year in 1974 through 1978. The plan would include a list of the utility's powerplants and fuels used, and a 10-year forecast of fuel consumption, electricity production, construction needs, and financial requirements for meeting the 1990 oil consumption target.

To modify existing, oil-fired powerplants to burn an alternate fuel and to construct new powerplants to replace oil-fired units, 5 billion dollars in direct grants and 10 billion dollars in loan guarantees would be made available. This financial assistance is designed to help the utilities meet oil consumption targets.

Changes to the proposed legislation are being considered based on an initial review. Revisions may occur which increase the amount of money allocated for direct grants to the utilities for constructing new powerplants or converting current oil-fired powerplants to coal to meet the oil consumption targets. The target year for 50 percent reduction may be shifted to 1995. Also, a combined oil and natural gas consumption ceiling may be specified, directly linking the reduction in natural gas consumption legislated by the Powerplant and Industry Fuel Use Act with President Carter's oil program.

3. PROJECTED IMPACTS OF THE PRESIDENT'S PROGRAM TO REDUCE UTILITY OIL CONSUMPTION

Methodology and Assumptions

The Midterm Energy Forecasting System (MEFS) was used to analyze the impacts of the President's Program to reduce utility oil consumption in 1990. MEFS is a large, integrated energy model which contains a submodel: the Electric Utility Dispatch Module. This module projects electric power generation and plant expansion, assuming regional demand will be met in a way to minimize marginal cost. The marginal cost of each plant consists of the operations and maintenance costs and fuel costs for producing one kilowatt hour of electricity and a capital cost component for new powerplants, which is defined as a levelized cost over the life of the plants. The submodel functions at the Department of Energy (DOE) regional level, with regional costs and demands. (See Appendix A.) The demand for electricity is represented in the model by constructing regional, annual, load duration curves, i.e., the demand for electricity at each hour of the year is ordered from largest to smallest.

The input data and modeling assumptions required by MEFS were those developed for the C-High Scenario of the Energy Information Administration's (EIA's) 1978 Annual Report to Congress (ARC), with the modifications listed in Appendix B. The world oil price assumed for the C-High Scenario in 1990 was $23.50 per barrel (1978 dollars). Several modifications made in the methodology since last year's annual report are documented in a prior service report.[1] Five additional modifications were made explicitly for this report. Because of the uncertainty in the capital cost estimates for new powerplants and the sensitivity of this study to that input variable, the high end of the range for capital costs and fixed charge factors from the 1978 ARC were used. If lower cost assumptions were chosen, replacement of oil-fired powerplants by new, coal-fired powerplants would be greater than those shown here. The low limits for nuclear capacity additions of the 1978 ARC were assumed, reflecting the impact of the accident at Three Mile Island delaying construction

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[1] "MEFS Runs Describing Alternative Implementations of the Powerplant and Industrial Fuel Use Act," Julie Zalkind and Reginald Sanders, United States Department of Energy, Energy Information Administration, August 1979.

on some units previously scheduled to be operational by 1990. No improvement in the load factor, the ratio of average demand for electricity over a year to peak demand, was assumed, due to the uncertainty of implementing peak load pricing and the potential impact. Instead, this effect was analyzed as a sensitivity case.

The average, annual growth rate in the demand for electricity from 1977 through 1990 is projected to be 4.2 percent. The shape of the annual, load duration curve is based on historical demand data from the Edison Electric Institute for 1977.

Case Results

Three cases were studied to determine the impact of the President's utility oil use reduction program. Cases I and II were designed to represent the high and low range on oil use by the electric utilities without the President's Program and Case III estimated its use with the program.

In Case I, the existing, oil-fired and gas-fired steam powerplants were assumed to operate providing a high oil use projection. This case approximated the actions of

some Public Utility Commissions that approve new capacity additions only when capacity is required to meet increases in demand.

Case II assumed economic decisions (cost minimizing over the life of the plant) on the construction of new powerplants and the selection of plants for operation, with capital costs leveled over the life of the plant. This case constitutes the lower bound on oil use, since new, coal-fired powerplants would substitute for oil plants when they have a lower marginal cost for producing electricity than the existing oil-fired powerplants. The oil-fired powerplants would be retired prematurely or used to increase the reserve supply. In this case, utility consumption of natural gas is also reduced given the assumptions on implementing the Powerplant and Industrial Fuel Use Act.

Case III limited the amount of oil consumed nationally by the electric utilities in 1990 to 50 percent of the oil currently used in steam plants and 100 percent of the oil used by plants meeting peak demand. The oil consumption

limit for this study was set at 850 thousand barrels a day which is half the average oil consumption of steam plants in 1976 through 1978 plus the total average oil consumption of peaking plants. This limit is a lower bound since it does not include estimated oil consumption by facilities under construction.

Table 2 compares the electric utility residual and distillate oil and natural gas consumption projected in 1990 for each of the three cases described above. In Case II, the economic dispatch case, total oil consumption is lower than Case I by 660 thousand barrels per day. Seventy-five percent of the reduction in residual oil consumed occurs in DOE Regions 2 (New York, New Jersey) and 9 (West). The remaining reduction occurs in Regions 1 (New England), 3 (Mid-Atlantic), and 6 (Southwest). When a national limit of 850 thousand barrels per day is placed on utility consumption of all oil, the residual oil use decreases to 600 thousand barrels per day. The additional reduction comes from Regions 5 (Midwest) and 9 (West). Distillate consumption does not vary significantly for the three cases because it is used mainly by turbines to meet peak demand and the alternative sources of power for peak demand, hydroelectric plants and gas-fired turbines are limited due to fuel and water constraints.

Table 2 Electric Utility Oil and Natural Gas Consumption: History and Alternate Projections for 1990

	1978	Build to Reserve Margin Case I	Minimize Life Cycle Costs Case II	President's Program Case III
Residual (thousand barrels per day)		1,352	679	600
Distillate (thousand barrels per day)		242	255	250
Total Oil	1,742	1,594	934	850
Natural Gas (billion cubic feet per year)	3,188	2,594	1,376	1,384

The only region with significant oil consumption that did not show a reduction in oil use in Case II over Case I was Region 4 (South Atlantic). In this region, the oil-fired plants are projected to be used in an intermittent mode. When the world oil price is assumed to be $23.50 (1978 dollars) in 1990, constructing a new coal-fired plant for this limited use is not economical. Both cases project 168 thousand barrels per day of residual oil to be consumed in 1990. Currently, however, Region 4 consumes approximately 290 thousand barrels per day for residual-fired steam plants, these projections represent a 42 percent reduction. Natural gas consumption decreases by 57 percent over the 1978 level in Cases II and III because of the restrictions assumed under the Powerplant and Industrial Fuel Use Act.

The projections of capacity for electricity generation in 1990 are shown in Table 3. The minimum capacity projection occurs in Case I, where capacity additions are limited to those needed to meet increased demand. In Cases II and III, 44 and 48 additional gigawatts of coal are built, respectively. The reserve margin is shown to exceed those in Case I by 7 percent in Case II and 8 percent in Case III. The largest regional growth of coal capacity occurs in Region 2 (New York, New Jersey), Region 6 (Southwest), and Region 9 (West). In each of these regions the additional coal capacity would operate in base mode, i.e., almost

Table 3 Electric Utility Generation Capacity and Reserve Margins: History and Alternate Projections for 1990 (Gigawatts)

Plant Type [a]	1978 [d]	1990 Build to Reserve Margin Case I	1990 Minimize Life Cycle Costs Case II	1990 President's Program Case III
Fossil Steam				
Coal		345	389	393
Oil [b]		103	104	103
Natural Gas		59	60	60
Total Steam	405	507	553	556
Nuclear	54	140	141	141
Hydroelectric	71	98	98	98
Turbines				
Distillate		71	73	73
Natural Gas	49	14	7	7
New Technologies [c]	1	14	14	14
Total Capacity	579	844	886	889
Peak Demand [e]	408	662	659	658
Reserve Margin [e] (percent)	34	27	34	35

[a] These capacity values represent capacity available to operate or contribute to reserve after scheduled retirements and after conversions to a new fuel type.

[b] 7.46 GWe of oil were assumed to be converted to coal by 1990 under ESECA orders.

[c] New technologies include geothermal, solar thermal, photovoltaics, ocean thermal, wind, biomass, low/med Btu combined cycle, central electric AFB.

[d] Energy Information Administration, Annual Report to Congress 1978, Volume Two, Washington, D.C., Energy Information Administration, 1979, DOE/EIA-0173/2.

[e] Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1978. Peak demand and reserve margin are based on summer capacity and non-coincident summer peak load.

continuous operation, replacing oil steam capacity or other plant types which then replace some of the oil capacity used in an intermittent mode of operation. The results indicate that the marginal cost of a new coal plant is more economical than an existing, oil-fired powerplant operating at 63 to 69 percent capacity utilization. The high fuel cost of the oil is the dominant cost factor for oil-fired steam plants. In this analysis, the world oil price is assumed to be $23.50 (1978 dollars) per barrel in 1990. Since there is considerable uncertainty in the projected world price of oil, the results would be expected to change if different prices were assumed. Higher oil prices than those assumed here would result in projections of more, new, coal-fired powerplants and less oil consumption in Case II and also higher average prices in Case I.

Table 4 shows a shift in the fuels used to generate electricity from oil and gas in Case I to coal in Cases II and III. Case III (President's Program) has results similar to Case II (Minimize Life Cycle Cost). Two factors cause the reduction in kilowatt hours generated from oil- and gas-fired steam plants. Some existing oil

Table 4 Electricity Generation by Fuel Type: History and Alternate Projections for 1990
(Billions of kWh)

Plant Type	1978 [b]	1990 Build to Reserve Margin Case I	1990 Minimize Life Cycle Costs Case II	1990 President's Program Case III
Fossil Steam				
Coal	1,615	1,829	2,079	2,092
Oil	276	329	178	160
Natural Gas	281	252	127	128
Total Steam		2,410	2,384	2,380
Nuclear		792	795	795
Hydroelectric		312	314	314
Turbines				
Distillate	31	27	32	32
Natural Gas		4	5	5
New Technologies [a]	3	84	84	84
Total Generation	2,206	3,629	3,614	3,610

[a] New technologies include geothermal, solar thermal, photovoltaics, ocean thermal, wind, biomass, low/med Btu combined cycle, central electric AFB.

[b] Energy Information Administration, Annual Report to Congress 1978, Volume Three, Washington, D.C., Energy Information Administration, 1979, DOE/EIA-0173/3.

capacity would no longer be economical to use because of assumed high fuel costs and would be assigned to inactive reserve. The remaining capacity would be operated but at a lower utilization rate, reducing both the amount of fuel required and the electricity produced. Gas-fired steam plants are projected to operate less due to the limit on natural gas use imposed by the Powerplant and Industrial Fuel Use Act. The small difference in total generation for the three cases is the result of slightly different electricity prices.

The preceding three tables indicate that the President's oil reduction program is economically justifiable. The results of Case II, which are based on optimal decisions for minimizing the marginal cost of producing electricity, are similar to the results of Case III with a national oil consumption limit. If utilities were not constrained by the amount of available capital to construct new powerplants and by their inability to obtain from the regulatory commissions rate increases beyond mere fuel cost allowances, utility planners would be expected to make decisions similar to the results shown in Case II. The effect of the President's Program would be to change the cost and

risk environment utility planners face today and make them expand capacity and operate plants which are more economic in the long term. The program would have only a limited impact on future capacity expansion plans and oil consumption if most utilities are making decisions similar to Case II. However, if the regulatory environment would otherwise limit capacity expansion, the impact of the oil reduction program would be great.

Table 5 shows the effect of a reduced oil consumption program on the average price of electricity to residential, commercial, and industrial customers. Case I projects average prices which are 0.23 mills per kilowatt hour or 0.5 percent less than Case III, the President's Program. The prices projected in Case III do not reflect the federal grants and loan guarantees associated with encouraging capital expansion and, therefore, in reality would be lower than shown in the Tables. Case II and III both project slightly higher prices due to increased, new generating capacity by 1990. Consumers must pay for the additional coal capacity constructed as well as continue paying for the oil-fired capacity that is

Table 5 National Average Electricity Prices by Sector: History and Alternate Projections for 1990 (Mills per kWh, 1978 Dollars)

Sector	1978 [a]	Build to Reserve Margin Case I	Minimize Life Cycle Costs Case II	President's Program Case III
Residential	40.30	45.84	45.97	46.07
Commercial	41.00	45.95	46.07	46.17
Industrial	25.90	33.98	34.12	34.21
National Average	34.60	40.58	40.72	40.81

[a] Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry for 1978, Edison Electric Institute, 1111 19th Street, N.W., Washington, D.C.

retired early but still remains in the utility's rate base. The high fuel cost of oil consumed in Case I does not entirely offset the cost of the additional capacity expansion represented in Cases II and III. However, two factors will cause the average prices under Case III, the President's Program, to be less than Case I in future years. First, the capital expenditures in the rate base for the additional coal capacity in Case III over Case I decline over time as the capital is depreciated. Second, oil prices are expected to continue rising rapidly relative to coal prices, which are expected to increase only slightly through 1995 due to the current excess supply: the large reserves; and the competitive nature of the coal industry. In the Annual Report to Congress 1978 for Series C, the projected, delivered coal prices to the electric utility sector have an average annual growth rate of 3.7 percent from 1977 through 1995. Therefore, the increased electricity prices due to the President's Program will be merely a short term effect.

The capital requirements estimates for the electric capacity construction, projected for each of the cases, are generated by the Capital Requirements Estimating

Model (CREMOD)[2] for electric utilties. This model disaggregates the new plant capacity projections over time, using the projected commissioning dates derived from utility construction plans. The model estimates the capital requirements by integrating the disaggregated estimates of new plant capacity for each year with the related time-phase (Capital Expenditure Profile) estimates of capital costs for each plant type.

The cumulative, capital requirements estimates generated for this analysis represent the cumulative capital expenditures (1978 dollars) required to support the construction work completed and the construction work in progress (CWIP), from 1979-1990 for one or more plant types. This expenditure includes those for plants under construction but not scheduled for completion until after 1990. The total capital requirement reflects both the direct plant-related capital expenditures and the capital service costs incurred during construction (interest during construction).

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[2] "A Capital Requirements Estimating Model for Electric Utilities," Logistics Management Institute, April 1979.

The requirements for national, cumulative capital expenditures and the related electric generation capacity projected for Cases I-III for 1979-1990 are summarized in Table 6. The total cumulative expenditures projections range from 199 billion dollars for Case I to 242 billion dollars for Case III.

The projections for total capacity additions range from 320 GWe for Case I to 379 GWe for Case III. Implementation of the oil reduction program (Case III) would result in the need for 59 GWe of additional capacity when compared to Case I and 17 GWe when compared to Case II. The increased capacity requirement of Case III is fulfilled by an increase in new, coal-fired plant capacity of 48 GWe, relative to Case I, and 4 GWe relative to Case II. The nuclear capacity additions required for each of the three cases are approximately equal to the assumed limit. This limit on potential new nuclear capacity built by 1990 was 95 GWe reflecting current utility plans and the long lead time to license and construct new nuclear reactors.

Table 6 Electric Utility Generation Capacity Additions and Capital Requirements: Alternative Projections for 1979-1990

	Capacity Additions 1979-1990 (Gigawatts)			Capital Requirements 1979-1990 [a] (Billion 1978 Dollars)		
	Build to Reserve Margin Case I	Minimize Life Cycle Costs Case II	President's Program Case III	Build to Reserve Margin Case I	Minimize Life Cycle Costs Case II	President's Program Case III
Nuclear	94	95	95	67	67	67
Coal	134	178	182	89	124	130
All Other	92	89	102	43 [b]	46 [b]	45 [b]
Total	320	362	379	199	237	242

[a] Includes capital expenditures for plants under construction but not scheduled for completion until after 1990. Excludes transmission and distribution costs.

[b] Includes the costs of all plant conversions.

The additional capital expenditures required as a result of implementing the oil reduction program (Case III) would range from a low of 5 billion dollars, when compared to Case II, to a high of 43 billion dollars, relative to Case I. The variations occur largely as a result of the expenditure differences for coal-fired plants. Case I results in an expenditure requirement of 89 billion dollars, whereas Case II and III require 124 billion and 130 billion dollars, respectively. The lower expenditure requirements for Case I are caused by requiring all oil plants to operate, which minimizes the need for new capacity additions, especially coal.

The requirements for cumulative capital expenditure for transmission and distribution (T&D) capacity additions are 100.04 billion, 99.87 billion, and 99.81 billion dollars for Cases I, II and III, respectively. The magnitude of these capital requirements are nearly equal in all three cases. Since distribution capacity additions are directly related to the total number of additional end-use customers, and the number of customers is the same for each of the three cases, the capital expenditures for the distribution component of T&D are also identical. Therefore, the requirements for transmission capacity additions is the

only component of T&D that can vary the relative capital expenditure requirements of each case. The requirements for transmission additions are directly related to the relative changes in peak demands among the three cases. Since the peak demands are relatively close, 662 GWe, 659 GWe, and 658 GWe for Cases I, II, and III, respectively, only small differentials exist between the cumulative capital expenditures for T&D capacity additions in all three cases.

Sensitivity to Load Management Assumptions

The Public Utility Regulatory Policies Act, part of President Carter's National Energy Act, requires each State Regulatory Authority and each nonregulated utility to consider changes to utility pricing policy to more accurately reflect the cost of generating electricity at different times of the day. The price of electricity at peak periods, when relatively inefficient capacity is operating, would be greater than other hours of the day. For the Annual Report to Congress 1978, the impact of this new pricing policy was assumed to be a reduction in the demand during the peak hours of the day, with no

reduction in the total yearly demand. A 3 percent improvement in the system load factor, that is average yearly demand divided by peak demand, was assumed for 1990.

Cases IV and V represent a sensitivity analysis of the impact of this new demand profile on Cases I and II, respectively. Tables 7 through 11 present electric utility fuel consumption, capacity, generation, and prices for these two sensitivity analysis cases. Since Case V projects less oil consumption by the utilities than the national constraint, it was assumed there would be no change from the Case V projections for the President's Program.

Table 7 shows that the projected oil consumption is sensitive to load management assumptions. In Case IV, where existing oil plants are not allowed to be retired early, residual oil consumption increases over Case I. The residual-fired steam plants are projected to operate at a higher annual utilization rate, reflecting the reduced demand during peaking hours but increased demand for base mode generation. DOE Regions 2 (New York, New Jersey), 4 (South Atlantic), and 9 (West) account for 87 percent of this increased

Table 7 Electric Utility Oil and Natural Gas Consumption: Sensitivity of Projections for 1990

	Build to Reserve Margin Case I	Minimize Life Cycle Costs Case II	Load Management and Build to Reserve Margin Case IV	Load Management and Minimize Life Cycle Costs Case V
Residual (thousand barrels per day)	1,352	679	1,587	454
Distillate (thousand barrels per day)	242	255	164	144
Total Oil	1,594	934	1,751	698
Natural Gas (billion cubic feet per year)	2,594	1,376	2,732	1,448

residual oil use. For Case V, the residual consumption decreases dramatically compared to Case II. In this scenario, coal-fired powerplants are projected to be built because of the lower marginal cost for base mode operation compared to existing oil-fired powerplants. More oil-fired powerplants are retired due to coal replacement and the reduced demand during peaking hours.

Table 8 shows the generating capacity projected to exist in 1990, and Table 9 shows the generation projections by fuel type. Coal capacity is higher by 69 GWe in Case V versus the 330 GWe in Case IV replacing the existing oil- and gas-fired capacity that was operating in base mode. Total projected capacity and reserve margins in 1990 are less in Cases IV and V compared to Cases I and II. Case IV has less new coal capacity than Case I because additional oil capacity is available to meet base demand since peaking demand is reduced in response to peak load pricing. In Case V, less turbine capacity is projected than Case II because of the decreased demand during peak nours. Generation projections show the same trends.

Table 8 Electric Utility Generation Capacity and Reserve Margin: Sensitivity of Projections for 1990 (Gigawatts)

Plant Type	Build to Reserve Margin Case I	Minimize Life Cycle Costs Case II	Load Management and Build to Reserve Margin Case IV	Load Management and Minimize Life Cycle Costs Case V
Fossil Steam				
Coal	345	389	330	399
Oil	103	104	103	104
Natural Gas	59	60	59	60
Nuclear	140	141	140	140
Hydroelectric	98	98	98	98
Turbines				
Distillate	71	73	58	53
Natural Gas	14	7	30	9
New Technologies	14	14	13	14
Total Capacity	844	886	831	877
Peak Demand	662	659	667	663
Reserve Margin (Percent)	27	34	25	32

Table 9 Electric Generation by Fuel Type: Sensitivity of Projections for 1990 (Billions of Kilowatt Hours)

Plant Type	Build to Reserve Margin Case I	Minimize Life Cycle Costs Case II	Load Management and Build to Reserve Margin Case IV	Load Management and Minimize Life Cycle Costs Case V
Fossil Steam				
Coal	1,829	2,079	1,803	2,150
Oil	329	178	380	127
Natural Gas	252	127	274	137
Nuclear	792	795	792	794
Hydroelectric	312	314	315	315
Turbines				
Distillate	27	32	11	12
Natural Gas	4	5	0	4
New Technologies	84	84	82	84
Total Generation	3,629	3,614	3,657	3,633

Table 10 presents the electricity prices projected for residential, commercial, and industrial customers. The prices are lower when load factor improvement is assumed. Less capacity exists in the rate base and less generation from peaking units is required, therefore reducing the average price of electricity. Prices increase in Case V compared to Case IV because of capital costs associated with additional new capacity.

The requirements for cumulative capital expenditure and the additions for associated, electric generation capacity in the load management sensitivity cases (IV and V) are presented in Table 11. The cumulative, capital expenditure requirements for Cases IV and V are 183 billion and 232 billion dollars, respectively, as compared to 199 billion and 237 billion dollars for Cases I and II. The corresponding projections for the electric generation capacity additions for Cases IV and V are 308 GWe and 353 GWe. The lower capital requirements for the load management cases reflect the impact of the improved load factors on reducing the total capacity additions required to fulfill the demand requirements.

Table 10 National Average Electricity Prices by Sector: Sensitivity of Projections for 1990 (Mills per Kilowatt Hour, 1978 Dollars)

	Build to Reserve Margin Case I	Minimize Life Cycle Costs Case II	Load Management and Build to Reserve Margin Case IV	Load Management and Minimize Life Cycle Costs Case V
Residential	45.84	45.97	45.40	45.51
Commercial	45.95	46.07	45.53	45.66
Industrial	33.98	34.12	33.45	33.62
National Average	40.58	40.72	40.11	40.25

Table 11 Electric Utility Generation Capacity Additions and Capital Requirements: Sensitivity of Projections for 1979-1990

Plant Type	Capacity Additions 1979-1990 (Gigawatts) Case IV	Capacity Additions 1979-1990 (Gigawatts) Case V	Capital Requirements 1979-1990 [a] (Billion 1978 Dollars) Case IV	Capital Requirements 1979-1990 [a] (Billion 1978 Dollars) Case V
Nuclear	94	95	67	67
Coal	119	188	73	123
All other	95	70	43 [b]	42 [b]
Total	308	353	183	232

[a] Includes capital expenditures for plants under construction but not scheduled for completion until after 1990. Excludes all transmission and distribution costs.

[b] Includes the costs of all plant conversions.

The capital expenditures requirements for transmission and distribution (T&D) additions for Cases IV and V are 95.81 billion and 95.02 billion dollars, respectively. The lower, total, capital expenditures requirements for T&D additions in the load management cases versus the base cases are a function of the reduced peak demand requirements created by improving the load factors of Cases I and II.

Although projections of utility oil consumption and capacity expansion vary with assumptions of the impact of peak load pricing, the important factor in reducing oil consumption is creating an economic environment similar to Cases II or V, where utility planners minimize the marginal cost of producing electricity. Without an oil reduction program, the high range of oil consumption by the utilities in 1990 is projected to be 1.59 to 1.75 million barrels per day and the low range .93 to .60 million barrels per day.

Summary

The results of this analysis indicate that the President's Program is economically justifiable. The projected capacity expansion and fuel use for electricity generation under the

President's Program are very similar to the projections that assume optimal capacity expansion programs, i.e., those which minimize the cost of producing electricity over the life of the plant. In the short term, replacing oil-fired powerplants with new coal-fired units would raise the price of electricity to the utility customers. However, the President's Program contains provisions for Federal grants and loan guarantees to reduce or eliminate this projected increase in customer prices. Finally, an additional 5-43 billion dollars in revenue would be required over projected utility plans for 1978-1990 to reduce utility oil consumption to 850 thousand barrels per day. The President's Program is designed to assist the utilities in obtaining this additional revenue. In general, the effect of the President's Program will be to make utilities develop capacity expansion plans for 1990 that are more economic and reduce future oil consumption.

APPENDIX A

Department of Energy Regions

	REGION*	STATES
I	NEW ENGLAND	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
II	NEW YORK/ NEW JERSEY	New Jersey, New York
III	MIDDLE ATLANTIC	Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia
IV	SOUTH ATLANTIC	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee
V	MIDWEST	Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin
VI	SOUTHWEST	Arkansas, Louisiana, New Mexico, Oklahoma, Texas
VII	CENTRAL	Iowa, Kansas, Missouri, Nebraska
VIII	NORTH CENTRAL	Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming
IX	WEST	Arizona, California, Hawaii, Nevada
X	NORTH WEST	Alaska, Idaho, Oregon, Washington

APPENDIX B

Modifications to the 1978 Annual Report to Congress C-High Scenario

1. The World oil price in constant 1978 dollars is $21.50 in 1985, $23.50 in 1990, and $31.50 in 1995.

2. Utilities are assumed to pay the marginal price of natural gas in the Southwest (Region 6) and are high-priority users in other regions paying the interstate regulated prices.

3. The maximum price for natural gas is 12 cents per million Btu (1978 dollars) below the wholesale price of residual oil.

4. Utilities may request an economic exemption that will permit unlimited consumption of natural gas.

5. Electric utility plants serving peakload demand may use natural gas all year.

6. Industrial boilers may use natural gas if it costs 12 cents per million Btu (1978 dollars) below the Btu - equivalent price of residual fuel oil at 0.8 percent sulfur level.

7. Utilities may build new, oil-fired steam plants but not gas-fired steam plants.

8. The discount rate for industrial investments subject to the regulatory program is 7.7 percent with full foresight on the fuel price trajectory.

9. The discount rate for other industrial investment decisions is 8 percent with half foresight.

10. The low nuclear capacity build limits to the 1978 ARC are assumed, reflecting the impact of the accident at Three Mile Island delaying construction on some units previously scheduled to be operational by 1990.

11. The high utility capital costs of the 1978 ARC are used. (See Appendix C.)

12. Modifications to the capital costs of coal-fired powerplants burning medium and low sulfur coal to reflect the revised New Source Performance Standards developed by the Environmental Protection Agency. (See Appendix C.)

13. The fixed charge factors of the high cost scenario of the 1978 ARC are used to annualize the Capital Costs of new powerplants. (See Appendix C.)

14. No improvement is assumed in the load factor as a result of peak load pricing.

APPENDIX C

Economic Values for New Coal-Fired Powerplants

Table 1. Capital Costs
(1975 Dollars per Kilowatt)

Plant Type	Department of Energy Region									
	1	2	3	4	5	6	7	8	9	10
Bituminous/High Sulfur/ with Scrubber	710	780	710	645	710	630	695	-	-	645
Bituminous/Medium Sulfur/ with Scrubber	680	745	680	615	680	600	670	645	695	615
Bituminous/Low Sulfur/ with Scrubber	615	675	615	560	615	545	605	640	690	560
Subbituminous/Medium Sulfur/ with Scrubber	705	770	705	640	705	625	695	680	730	640
Subbituminous/Low Sulfur/ with Scrubber	640	700	640	585	640	575	630	670	720	585
Lignite/Medium Sulfur/ with Scrubber	725	805	725	660	725	645	715	700	755	660
Lignite/Low Sulfur/ with Scrubber	665	735	665	605	665	590	655	695	745	605

Table 2 Fixed Charge Factors
(percent)

Plant Type	Value
Bituminous/High Sulfur/with Scrubber	10.4
Bituminous/Medium Sulfur/with Scrubber	10.3
Bituminous/Low Sulfur/with Scrubber	10.1
Subbituminous/Medium Sulfur/with Scrubber	10.3
Subbituminous/Low Sulfur/with Scrubber	10.1
Lignite/Medium Sulfur/with Scrubber	10.0
Lignite/Low Sulfur/with Scrubber	9.8

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